State of California
Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2003 Through December 31, 2003

With Reexamination and Redetermination For the Period

January 17, 2001 Through December 31, 2002

To Be Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

June 14, 2002

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A. PURPOSE OF DETERMINATIONS

General

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement between the State of California Department of Water Resources (the "Department") and the California Public Utilities Commission (the "Commission") dated as of March 8, 2002 (the "Rate Agreement"), the Department plans, by means of this Determination of Revenue Requirements (this "Determination"), to advise and notify the Commission of (1) the result of the Department's reexamination of its revenue requirement for the period January 17, 2001, through and including December 31, 2002 (the "First Revenue Requirement Period"), and (2) its revenue requirement for the period January 1, 2003, through and including December 31, 2003 (the "Second Revenue Requirement Period," and collectively with the First Revenue Requirement Period, the "Revenue Requirement Periods"). The Department has made these revenue requirement and "just and reasonable" determinations in accordance with California Water Code, Division 27 (the "Act") and California Code of Regulations, Division 23, Chapter 4, Sections 510–517 (the "Regulations"). The notice of proposed determination has been sent to the persons or entities that provided comments or requested notice of the prior determination dated November 5, 2001, and any other persons or entities requesting notice of this current revenue requirement determination. The deadline for submitting comments was July 5, 2002. The Department held a workshop at 12:30 p.m. on June 19, 2002, at the Auditorium of the Employment Development Department, 722 Capitol Mall, Sacramento, which focused on a review of the Department's proposed revenue requirement determination.

The Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the investor-owned utilities (the "IOUs") on January 17, 2001 when the IOUs were no longer creditworthy and could not purchase energy in the market. On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was enacted into law, containing, among other things, the Act. The Act authorized the Department to purchase the net short energy requirements of the customers. The "net short" is equal to total IOU energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department has, per the requirements of the Act, procured the net short requirements of the IOUs using a combination of long-term energy contracts and short-term energy purchases. The amount of energy required to be purchased on a short-term basis, after the application of energy from long-term contracts entered into by the Department, is referred to as the "residual" net short. The costs of the Department's purchases to meet the net short requirements of the customers of the IOUs are recovered from payments made by the customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Rate Agreement, dated as of March 8, 2002, between the Department and the California Public Utilities Commission (the "Rate Agreement"). Among other items, the Rate Agreement establishes the foundation for a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its intended bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's "Retail Revenue Requirements" (as that term is defined in the Rate Agreement), including power supply related costs.[1]

The Department funded its purchases for energy from January 17, 2001, to date from a combination of Customer revenue collected by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of $4.3 billion in June 2001 (the "Interim Loan"). Approximately $7 billion of power costs paid by the Department to meet the net short energy needs of the Customers have not yet been reflected in retail electric rates. These costs will be reimbursed from the proceeds of a revenue bond financing of up to $11.1 billion, the repayment of which will be made from the bond charge established in the Rate Agreement, as described in more detail herein.

The Department, consistent with the Act, has procured the entire net short requirement of the IOUs and has provided the Commission with information on its costs of such procurement activities in its November 5, 2001 determination of revenue requirements and subsequent updates to the November 5, 2001 filing. A section within this determination re-examines the Department's costs implemented in rates in the Commission's Decisions 02-02-052 and 02-03-003, as modified by Decision 02-03-062 (collectively, the "2001-2002 Rate Decision"). While the Act states that the Department's responsibility for the procurement of the residual net short requirements of the utilities' terminates as of December 31, 2002, the Act permits the Department to manage its then existing portfolio of longer-term contracts through their respective terms. Thus, a principal assumption in the determination of revenue requirements over the period January 1, 2003, through December 31, 2003, is that the Department will no longer be responsible for the acquisition of the IOUs' residual net short energy requirements and only the costs associated with the Department's long term contracts and their administration are included. A later section of this determination provides preliminary estimates of the costs associated with the Department's continued involvement in the procurement of the residual net short requirements of the IOUs, if the Department's continued involvement were to be necessary and legally authorized.

Additionally, the Department has been actively renegotiating its existing portfolio of longer-term contracts. A summary of the changes to its existing portfolio of contracts and a description of the expected impact on the Department's costs are included in Section C of this determination.

As per the requirements of Section 80134 of the California Water Code and the Rate Agreement, this Determination contains information on the amounts required to be recovered in the Revenue Requirement Periods. Additionally, a reconciliation of the Department's revenue requirements through the first quarter of 2002 relative to the

[1] Subject to the conditions described in the Rate Agreement and other Commission decisions, Bond Charges and charges servicing certain of the purposes of Power Charges may also be imposed on the customers of other electric service providers. The implementation of such charges would, of course, affect the amounts described in this Determination as needed to be recovered from Bond Charges and Power Charges.

amounts provided in the 2001-2002 Rate Decision[1] is presented. This reconciliation, together with revised projections for the remainder of 2002 and related Department determinations, will constitute the re-examination of the Department's revenue requirement for the First Revenue Requirement Period.

For the Second Revenue Requirement Period, this determination contains information on the following[2]: (a) the beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts on deposit in each account and sub-account of the Fund, (b) the amounts necessary to pay or provide for the principal of, premium, if any, and interest on all bonds and all other Bond Related Costs as and when the same shall become due and the aggregate amount of bond charges projected to be required to be collected for such purpose, and (c) the amount of the Department's Retail Revenue Requirements.

Determination of Revenue Requirements

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the materials referred to in Appendix 3), that its cash basis revenue requirement for the Second Revenue Requirement Period, to be implemented by charges calculated and imposed by the Commission, is $5.539 billion, consisting of $840 million in Bond Related Costs and $4.699 billion in Retail Revenue Requirements.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with its expected Power Charges for the Second Revenue Requirement Period. A similar summary of the Department's revenue requirements and accounts associated with its Bond Charges are presented in Table A-2. Definitions of key accounts and subaccounts are presented within each table.

The Department further determines, also on the basis of the materials presented and referred to by this Determination (including the materials referred to in Appendix 3), that its total retail revenue requirement over the First Revenue Requirement Period, taking into account results of operations through the first quarter of 2002, is $9.045 billion. The Department also estimates that it will have recovered a total of $9.118 billion in revenues during the First Revenue Requirement Period from the Department charges imposed in the 2001–2002 Rate Decision.[3]

[1] Appendix A, Table 1 of the California Public Utilities Commission, Decision 02-02-052 in Application 00-11-038 et al., dated February 21, 2002.

[2] Where appropriate, the Department has provided information on a monthly basis for the revenue requirement period. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on a quarterly or an annual basis and will provide monthly detail as well as its model under seal to signatories of a non-disclosure agreement with the Department. The Department and its consultants will remain available to answer further questions regarding the model and the data used in this determination of revenue requirements.

[3] The amount of the revenue requirements to be implemented by the Commission for the Second Revenue Requirement Period assumes that the Department charges imposed by the 2001–2002 Rate Decision remain in effect for the entire First Revenue Requirement Period.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND ACCOUNTS: POWER CHARGE ACCOUNTS[1]

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)
1	***Balance in Power Charge Accounts***	
2	Operating Account	557
3	Priority Contract Account	427
4	Operating Reserve Account	896
5	**Total Beginning Balance in Power Charge Accounts**	**1,881**
6	***Power Charge Accounts Operating Revenues***	
7	Power Charge Revenues	4,699
8	Other Power Sales	101
9	Interest Earnings on Fund Balances	59
10	**Total Power Charge Accounts Operating Revenues**	**4,859**
11	***Power Charge Accounts Operating Expenses***	
12	Administrative and General Expenses	28
13	Contract Costs	4,095
14	Spot Purchases	—
15	Ancillary Services	171
16	Other Operating Expenses	
17	**Total Power Charge Account Operating Expenses**	**4,295**
18	Net Operating Revenues	564
19	Net Transfers from Bond Charge Accounts	(224)
20	Beginning Balance in Power Charge Accounts	1,881
21	**Ending Aggregate Balance in Power Charge Accounts**	2,220

2003 Target Minimum Power Charge Account Balances	Target in millions
Operating Account: A minimum balance of $220 million is targeted to cover intra-month volatility as measured by the maximum difference in revenue and expenses.	$220
Priority Contract Account: The minimum balance is the maximum monthly priority contract costs for the revenue requirement period.	$427
Operating Reserve Account: Used to satisfy deficiency in Operating Account. It is sized as a rolling seven-month difference between operating revenues and expenses as calculated under "stress" operating conditions.	$896

[1] Prior to the issuance of bonds, includes amounts in the entire Electric Fund.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND ACCOUNTS: BOND CHARGE ACCOUNTS

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)
1	*Beginning Balance in Bond Charge Accounts*	
2	Bond Charge Collection Account	47
3	Bond Charge Payment Account	238
4	Debt Service Reserve Account	699
5	Parity Obligation Reserve Account	–
6	Administrative Cost Account	–
7	**Total Beginning Balance in Bond Charge Accounts**	**985**
8	*Bond Charge Account Revenues*	
9	Bond Charge Revenues from Utilities	840
10	Interest Earnings on Fund Balances	27
11	**Total Bond Charge Account Revenues**	**868**
12	*Bond Charge Account Expenses*	
13	Debt Service on Bonds	573
14	Other Bond Charge Account Expenses	–
15	**Total Bond Charge Account Expenses**	573
16	Net Bond Charge Revenues	295
17	Net Transfers from Power Charge Accounts	224
18	Beginning Balance in Bond Accounts	985
19	**Ending Aggregate Balance in Bond Charge Accounts**	**1,505**

2003 Target Bond Charge Account Balances	Target Balance
Bond Charge Collection Account: An amount equal to one month's projected debt service	$47
Bond Charge Payment Account: Funded initially with monthly debt service deposits funded three months in advance	$143
Debt Service Reserve Account: Established at maximum annual debt **service**	$932

Table C-1 shows, among other things, a summary of the Department's revenue requirements associated with its power charges for the First Revenue Requirement Period.

Determination That Revenue Requirements Are Just and Reasonable

Pursuant to the Act and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the materials referred to in Appendix 3), that the revenue requirements determined hereby are just and reasonable within the meaning of the Act and the Regulations.

Future Adjustment of Revenue Requirements

The Department notes that because the California energy market and its participants continue to undergo rapid change, the Department may need to revise its revenue requirements for the Revenue Requirement Periods. Factors that may influence the Department's revenue requirements for the Revenue Requirement Periods include, but are not limited to:

(1) Decisions adopted by the Commission in its deliberations regarding direct access for customers that opt for generation service from an Electric Service Provider (ESP).

(2) Changes to the Department's responsibility for providing the net short and residual net short requirements of the customers of IOUs.

(3) Financing related factors, including, but not limited to, the timing of the issuance of the bonds and the final structure and terms of the bonds.

(4) Changes to the California electricity market-place. The California Independent System Operator ("CAISO") is undergoing a process of redesign for the operation of the transmission system and the movement of bulk (wholesale) power in California. The redesign, called Market Design 2002 ("MD02"), is being carried out in response to orders issued by the Federal Energy Regulatory Commission ("FERC"). The FERC Order on Clarification and Rehearing of December 19, 2001, directed the CAISO to file its revised congestion management proposal and a plan for implementation of a day-ahead market. In addition, the CAISO is responding to the impending expiration on September 30, 2002, of the market monitoring and mitigation program instituted by the FERC in its Order on Rehearing of Monitoring and Mitigation Plan, issued on June 19, 2001. To the extent that changes to the California electricity marketplace may arise on account of these ongoing initiatives, there may be a material change in the Department's revenue requirements in both the First and Second Revenue Requirement Periods. In the event that such changes may materialize, the Department will, first, inform the Commission of such changes and, second, revise its revenue requirement projections accordingly.

These factors are discussed in more detail within the section titled "Key Uncertainties in the Revenue Requirement Determinations."

B. BACKGROUND

Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that any "just and reasonable" review of its revenue requirements shall be conducted and determined by the Department. Additionally, Section 80134 of the Water Code provides that:

"(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:

"(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.

"(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.

"(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.

"(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.

"(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.

"(6) The administrative costs of the Department incurred in administering this division.

"(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110."

Pursuant to the requirement of Sections 80110 and 80134 of the California Water Code, the Department submitted an initial estimated determination of revenue requirements to the Commission on May 2, 2001, covering the period from January 17, 2001, through and including May 31, 2002. Following this initial submittal, the Department provided the Commission with updates dated July 23, 2001, August 7, 2001, and November 5, 2001, all of which covered the period January 17, 2001, through and including December 31, 2002. In its determination of revenue requirements dated November 5, 2001, the Department estimated a total revenue requirement of $10,003,461,000 for the period January 17, 2001, through and including December 31, 2002. On February 21, 2002, the Department advised the Commission that the costs needed to be recovered by the 2001-2002 Rate Decision could be reduced by $958 million.[1] The Commission, in its 2001-2002 Rate Decision, implemented cost recovery of the Department's revenue requirements, adjusted by that amount. A summary of the Commission's implementation of the Department's revenue requirements is provided Section C, Table C-1

Concurrent with its action on the 2001-2002 Rate Decision, the Commission issued a decision adopting a Rate Agreement between itself and the Department establishing the procedures to be followed to calculate and adjust the charges to the Customers for Department power, such that the Department is assured of recovering its retail revenue requirement.[2] The purpose of the Rate Agreement is to facilitate the issuance of bonds that enable the repayment of the General Fund, Interim Loan, and the funding of appropriate reserves for the bonds.[3]

The Rate Agreement between the Commission and the Department establishes two streams of revenue for the Department. One stream of revenue is generated from "Bond Charges" imposed on Customers for the purpose of providing sufficient funds to pay "Bond-Related Costs." Bond Charges are applied based on the aggregate amount of electric power sold to each Customer by the Department and the applicable IOU, and, to the extent provided by final non-appealable Commission orders, third-party power providers. Bond-Related Costs include Bond debt service, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements entered into in connection with the Bonds. The Bond Charges will be imposed upon Customers whether or not the Department is selling power to those customers. The Rate Agreement requires the Commission to impose Bond Charges that are sufficient to pay all Bond-Related Costs as they come due.

The second stream of revenue is generated from "Power Charges" imposed on Customers who buy power from the Department, and is designed to pay for "Department Costs," including the costs that the Department incurs to procure and

[1] The two major components of the change were (a) a reduction of $609 million on account of the Commission's draft order in the Utility Retained Generation (URG) proceeding considering requiring the investor owned utilities to reimburse the Department for certain CAISO-related costs and (b) a reduction of $349 million on account of a revision to the assumption regarding the timing of the bond issuance to repay the Department's Interim Loan (as well as the General Fund).

[2] California Public Utilities Commission, Decision 02-02-051, "Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources," adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

[3] To fund the power program, the Department has relied on customer revenues, the General Fund Loans, the proceeds of an interim loan of $4.3 billion entered into on June 26, 2001, with several financial institutions (the "Interim Loan"), and revenues collected from the Customers to satisfy its revenue requirements associated with the power supply program. The Department plans to issue bonds in the 3rd quarter of 2002 the proceeds of which will be used, in part, to reimburse the State's General Fund for the General Fund Loans and repay the Interim Loan.

deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements (defined below) specified by the Department. Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in and accounted for in the fund established by the Department for the procurement of power supply resources under the Act (the "Electric Power Fund").

To enable the Commission to set Bond Charges and Power Charges, the Rate Agreement requires the Department to submit its "Retail Revenue Requirements" to the Commission. The Rate Agreement defines Retail Revenue Requirements as the amount of Department Costs that must be recovered from Power Charges. The Rate Agreement uses the Department's submittal of its Retail Revenue Requirements as a vehicle for the Department to notify the Commission not only about Department Costs, but also about Bond-Related Costs.

Revenues from Power Charges will be deposited into an "Operating Account." Funds in the Operating Account will be used to pay for Department Costs, and funds will also be transferred to a "Priority Contract Account." The Priority Contract Account will be used to pay for the costs that the Department incurs under its Priority Long-Term Power Contracts ("PLTPCs"), which have terms that require the Department to pay for power purchased under these contracts ahead of Bond-Related Costs (such as Bond debt service).

In addition, the Department will fund an "Operating Reserve Account" to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges will be deposited into a "Bond Charge Collection Account." Funds in the Collection Account will be transferred periodically to a "Bond Charge Payment Account." Funds in the Bond Charge Payment Account may only be used to pay Bond-Related Costs. However, so long as funds remain in the Bond Charge Collection Account, they may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs. If the Bond Charge Collection Account is used to fund amounts due under PLTPCs, the Bond Charge Collection Account will be replenished from Power Charges.

The Department is making this determination of revenue requirements consistent with the requirements of Section 80110 and 80134 of the California Water Code and is providing information consistent with the reporting requirements specified within the Rate Agreement.

Consistent with the terms and conditions of the Rate Agreement, the Department may, depending on its operating circumstances, revise the revenue requirements contained within this determination of revenue requirements. The Department will notify the Commission when such a revision is warranted and provide the necessary information for the Commission to implement the appropriate power charges and bond charges during the course of the revenue requirement period.

C. RECONCILIATION OF REVENUE REQUIREMENTS IMPLEMENTED IN THE 2001–2002 RATE DECISION, WITH RESULTS OF OPERATIONS THROUGH AND UPDATED PROJECTIONS FOR 2002

On February 21, 2002, in the 2001–2002 Rate Decision, the Commission implemented the Department's revenue requirement, adjusted as described above, in the amount of $9.045 billion. This revenue requirement covered the period of January 17, 2001, through December 31, 2002.

In adopting the Department's revenue requirement, the Commission noted the Department intends to submit a true-up of prior periods each time it submits its new revenue requirement for the coming year (2003).

The Department has reviewed the results of operations through the first quarter of 2002 and its projections for the balance of 2002. For the First Revenue Requirement Period, the revenue requirement determined hereby, $9.112 billion, is $66 million more than the revenue requirement implemented by the Rate Decision, $9.045 billion, a difference of 0.7 percent. The reasons for the five most significant line item differences in Table C-1 are discussed below.

TABLE C-1
RECONCILIATION OF PRIOR PERIOD REVENUE REQUIREMENTS
(Thousands of Dollars)

	Adopted 2001	Results 2001	Difference	Adopted 2002	Revised 2002	Difference	Total Adopted	Total Revised
Retail Sales (GWh)	58,399	55,639	(2,760)	40,394	43,051	2,657	98,793	98,690
Contract Power	$2,186,475	$2,090,518	($95,957)	$3,097,788	$3,336,636	$238,848	$5,284,263	$5,427,154
Residual Net Short	8,850,011	8,778,701	(71,310)	684,187	490,197	(193,990)	9,534,198	9,268,898
Ancillary Services	888,618	964,049	75,431	213,061	266,990	53,929	1,101,679	1,231,039
A&G	38,354	67,379	29,025	60,416	60,417	1	98,770	127,796
DSM	288,896	288,896	0	0	157,149	157,149	288,896	446,045
Other (Uncollectibles)	7,742	18,191	10,449	16,022	13,682	(2,160)	23,764	32,053
Total Commitments	$12,260,096	$12,207,734	($52,362)	$4,071,474	$4,325,251	$253,777	$16,331,570	$16,532,985
Led/(Lag) Accrual to Cash	(1,221,090)	(872,164)	348,926	1,210,442	677,912	(532,530)	(10,648)	(194,252)
Total Operating Expenditures	$11,039,006	$11,335,570	$296,564	$5,281,916	$5,003,163	($278,753)	$16,320,922	$16,338,733
Financing Costs	(10,481)	(9,981)	500	942,559	926,834	(15,725)	932,078	916,853
Total Expenditures	$11,028,525	$11,325,589	$297,064	$6,224,475	$5,929,997	$(294,478)	$17,253,000	$17,255,586
Revenue Lead/(Lag)	1,483,689	1,490,678	6,989	(837,556)	(1,088,396)	(250,840)	646,133	402,282
Spot Sales Revenue	(20,884)	0	20,884	(136,020)	(46,176)	89,844	(156,904)	(46,176)
Estimated Fund Balance				1,495,658	1,611,236	115,578	1,495,658	1,611,236
Total DWR Revenues Needed	$12,491,330	$12,816,267	$324,937	$6,746,557	$6,406,761	($339,796)	$19,237,887	$19,223,028
Net Borrowed Proceeds	(10,192,429)	(10,192,429)	0	0	81,274	81,274	(10,192,429)	(10,111,155)
Rounding Difference							3	
Customer Revenue Requirement	$2,298,901	$2,623,838	$324,937	$6,746,557	$6,325,487	($421,070)	$9,045,461	$9,111.873

Contract Power and Residual Net Short

During April and May of 2002, the Department was successful in renegotiation of 16 contracts with six different power suppliers, resulting in long-term savings, but also increasing available energy at lower costs during 2002. The projected increase of $143 million in Contract Power is more than offset by the decrease of $265 million in Residual Net Short purchases.

Ancillary Services

Ancillary Services projections have increased by $129 million or about 12 percent over the adopted amount. The Department is paying for Ancillary Services for the benefit of PG&E. It is assumed for purposes of this Determination that these costs will be recovered from PG&E in the future and do not need to be included in the Department's retail revenue requirement.

Demand-Side Management (DSM)

When the current Revenue Requirement was adopted in February 2002, there was no provision for a 20/20 conservation program in 2002. With the approval of the program for residential customers to be effective during this summer, the Department projects a net cost for the Department in the amount of $157 million. Lower Department revenues, offset in part by anticipated energy savings resulting from this program, have been included in the various projections.

Lead/Lag Accrual to Cash

The increase of nearly $184 million in cash lag is primarily due to delays in collection of Ancillary Services costs from PG&E and in the timing of IOU-disputed catch-up payments.

D. THE DEPARTMENT'S REVENUE REQUIREMENTS FOR THE SECOND REVENUE REQUIREMENT PERIOD

Retail Revenue Requirement

For the Second Revenue Requirement Period, which commences January 1, 2003, and ends December 31, 2003, the Department's Retail Revenue Requirement consists of Power Charge-Related Costs and Revenues and Bond Charge-Related Costs and Revenues.

Power Charge-Related Costs include:

(1) Costs associated with power supply to be delivered to the Department under existing PLTPCs;

(2) Operating reserves as determined by the Department (see Table A-1);

(3) Administrative and general expenses; and

(4) Costs associated with ISO grid reliability purchases or ancillary services.

Power Charge-Related Revenues include:

(1) Revenues from Other Power sales;

(2) Interest earnings; and

(3) Customer Power Charge Revenue Requirement.

Table D-1 provides a quarterly review of costs and revenues associated wit the Power Purchase Program.

Over the Second Revenue Requirement Period, the Department projects that it will incur the following costs: (a) $4.095 billion in costs for power purchases to cover the net short requirement of the Customers; (b) $172 million to acquire ancillary services and associated energy not otherwise provided by the IOUs from their retained generation; (c) $28 million in administrative and general expenses; (d) $225 million of net transfers to Bond charge accounts to meet trust indenture requirements; and (e) $339 million in charges to power charge accounts, for a total of $4.860 billion in costs.

Funds to meet these costs are provided from (a) $101 million from power sales revenues to the spot market; (b) $59 million of interest earned on power charge account balances; and (c) $4.699 billion from Retail Customers power charges.

TABLE D-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT
(Millions of Dollars)

Period	Power Cost	Ancillary Services	Administrative and General Expenses	Net Transfers to Bond Charge Accounts	Changes to Power Charge Account Balances	Total Power Charge Account Expenses	Other Power Sales Revenues	Interest Earnings on Power Charge Account Balances	Required Retail Customer Power Charge Revenue Requirement	Total
Q1-2003	$909.0	$60.8	$7.1	$173.6	($10.8)	$1,140.0	$11.6	$21.5	$1,106.7	$1,139.8
Q2-2003	835.2	33.0	7.1	51.3	(62.0)	864.6	37.5	–	827.1	864.6
Q3-2003	1,215.0	29.5	7.1	–	120.9	1,372.6	25.7	38.1	1,308.9	1,372.6
Q4-2003	1,135.9	48.4	7.1	–	291.4	1,482.8	26.1	–	1,456.6	1,482.8
Total	$4,095.2	$171.7	$28.4	$224.9	$339.5	$4,860.0	$101.0	$59.5	$4,699.3	$4,859.8

Bond-Related Costs include:

(1) Debt Service payments; and

(1) Changes to Bond Charge Account Balances.

Bond-Related Revenues include:

(1) Interest earned on Bond Account Balances;

(2) Transfers from Power Charge Accounts; and

(3) Customer Bond Charge Revenue Requirement.

Table D-2 provides a quarterly summary of expected Bond Related Costs and Revenues for the Second Revenue Requirement Period.

TABLE D-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT
(Millions of Dollars)

Period	Debt Service Payments	Other Bond Charge Account Expenses	Changes to Bond Charge Account Balances	Total Bond Charge Account Expenses	Interest Earnings on Bond Charge Account Balances	Net Transfers from Power Charge Accounts	Retail Customer Bond Charge Revenue Require-ment	Total Bond Revenue
Q1-2003	$58.3	–	$227.6	$285.9	$2.8	$173.6	$109.4	$285.9
Q2-2003	228.4	–	49.1	277.5	–	51.3	226.2	277.5
Q3-2003	58.3	–	236.0	294.3	25.0	–	269.2	294.3
Q4-2003	228.4	–	7.1	235.5	–	–	235.5	235.5
Total	$573.3	–	$519.9	$1,093.1	$27.9	$224.9	$840.3	$1,093.1

Over the Second Revenue Requirement Period, the Department projects that it will incur the following costs related to Bond Requirements: (a) $573.3 million for payments to meet Debt Service requirements and (b) $519.8 million for Changes to Bond Charge account balances, resulting in total Bond Charge Account expenses of $1.093 billion.

Funds to meet these requirements are provided from (a) $27.9 million in Interest Earned on Bond Charge account balances; (b) $224.9 million of Net transfers from Power Charge Accounts; and (c) $840 million from Customers Bond Charges.

Added together, the Department's total Power and Bond costs are $5.953 billion. Revenues from Interest earned and Other Power Sales are $413 million, resulting in combined Customer Revenue Requirements of $5.540 billion.

E. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE SECOND REVENUE REQUIREMENT PERIOD

The Department's estimate of its Retail Revenue Requirements for the period January 1, 2003, through and including December 31, 2003, are based on a number of assumptions regarding sales, power supply, natural gas prices, off-system sales, the costs of ancillary services, demand side management and conservation, administrative and general expenses, and an allowance for uncollectibles.

Load and Sales Forecast

As the starting point for its estimates of IOU demand and energy requirements, the Department obtained the most recent load projections available from each IOU.[1] Each IOU forecast was generated by econometric models that rely on statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.[2]

Table E-1 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this revenue requirement determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. Southern California Edison Company ("SCE") derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), while San Diego Gas and Electric Company ("SDG&E") relied on a DRI forecast of economic trends in its service area.

The initial IOU load forecasts were adjusted for several factors including self-generation, direct access, conservation and load management, and price elasticity.

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[1] The IOUs typically do not issue new demand and energy projections annually. For PG&E, the Department relied on a projection prepared in April 2002 for PG&E's 2003 General Rate Case ("GRC"). The projection used for SCE was prepared in May 2001 and is being used for its Test Year 2003 GRC. For SDG&E, NCI relied on a forecast prepared in the second half of 2001 for use in SDG&E's 2003 cost of service proceedings before the Commission.

[2] The IOUs' load forecasts and forecasting models have received detailed scrutiny in numerous regulatory proceedings over the years. In addition to scrutiny by the Commission, the Federal Energy Regulatory Commission ("FERC"), and numerous regulatory interveners, the Commission's Office of Ratepayer Advocates customarily reviews and critiques the IOUs' forecasts based on its own independent load forecasts using its own econometric models. Typically, the differences between the IOUs' forecasts and those prepared by the Office of Ratepayer Advocates have been small. The high level of scrutiny of these forecasts by regulatory agencies and the acceptance of the projections for revenue allocation and rate setting purposes provide support for the reasonableness of the IOUs' forecasting efforts.

TABLE E-1
MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS OF THE INVESTOR-OWNED UTILITIES

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth[1]	1.3	1.8	1.4[3]
Number of Households[1]	1.3	1.0	1.7[3]
Non-Farm Employment[1,2]	1.0	1.1	2.1[3]
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: PG&E data from work papers submitted in PG&E's Notice of Intent for its 2003 GRC. SCE data from Notice of Intent for Test Year 2003 GRC. SDG&E data provided by the IOU.
[1] Percent per year increase during 2002 and 2003, except as noted.
[2] Actual growth during 2001 was 1.2 percent statewide, according to the State Department of Finance.
[3] Annual percent growth from 2000 through 2006.

Self-Generation

In March 2001, the Commission announced a major five-year Self-Generation Incentive Program to encourage installation of efficient and/or renewable generation technologies with a capacity of one MW or less. The incentives range from 30 percent of the systems' cost, up to a maximum of $1,000 per kW for micro-turbines and for internal combustion engines utilizing waste heat recovery, and up to a maximum of $4,500 per kW for photovoltaics, wind turbines, and fuel cells operating on renewable fuels. The State has committed approximately $125 million per year in incentives through 2005. During 2001, approximately 129 applications representing 43 MW of installed capacity were funded through this program. Applications for the program were not accepted prior to July 2001 and, therefore, program participation is expected to exceed these levels during 2002. These incentives are expected to produce approximately 67 MW of incremental self-generation capacity per year through 2005.

Together with facilities constructed as a result of the Self-Generation Incentive Program, improvements in technology, increased concern over service reliability, and higher electricity prices are expected to result in a total increase in installed self-generation capacity of approximately 1,524 MW by 2010. This estimate was developed based on applications for interconnections made during 2001, installations coming on-line in 2001, and discussions with program mangers, equipment vendors, and the IOUs. Incremental annual additions during 2002 through 2005 are estimated to range from 180 to 210 MW, inclusive of Self-Generation Incentive Program additions.

Direct Access

In accordance with the provisions of AB1X, the Commission issued an interim order suspending direct access effective September 20, 2001. A final order affirming the September 20, 2001, suspension date was issued by the Commission on March 21, 2002 (the "Direct Access Order"). Electric end-users that elected to acquire service from alternative suppliers on or before September 20, 2001, will continue to be eligible for direct access service. The Commission estimates that approximately 14 percent of total IOU load qualified for direct access service under the Direct Access Order. The Direct Access Order:

- States that direct access will remain suspended until DWR is no longer providing power to the Customers.
- Prohibits the IOUs from accepting any new Direct Access Service Requests ("DASR") not already approved by the Commission, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service.[1]
- Contemplates the possible establishment by the Commission, at a future date, of a charge on direct access Customers ("direct access charge"). The direct access charge will be set at a level that prevents cost shifting as a result of direct access.[2]

Assembly Bill 117 ("AB 117"), under consideration by the California Legislature, would authorize electric end-users, including the Customers, to aggregate their electric loads with private aggregators as individual users, or with community choice aggregators as members of a local community, for the purpose of securing power supply from a party other than the IOUs. AB 117 would require a Customer that purchases power from a community choice aggregator to pay the Department a direct access charge to recover any difference between the Department's procurement costs and the rates collected by the Department from the Customer during the term of service, as well as the Department's net unavoidable cost of future power procurement that is attributable to the Customer.

For purposes of this determination, no incremental participation in direct access, beyond that authorized by the Direct Access Order has been assumed.

Conservation and Load Management

During 2001, total sales by the IOUs declined by approximately 5.5 percent compared to 2000. Analyses completed by the California Energy Commission ("CEC") conclude that this reduction was not generally attributable to weather or economic activity. Rather, the load reductions are believed to have primarily resulted from (a) reductions in usage stemming from heightened awareness of California's energy crisis and public appeals to conserve energy, and reductions resulting from Customer reactions to significant increases in electricity rates and prices and (b) impacts of new initiatives and additional funding to promote energy conservation and load management, including rebates, voluntary load reduction programs, revised retail rate

[1] However, these customers may renew their direct access service contracts upon their expiration or transfer them to a new service location as long as the load served is of comparable size.

[2] That is, the Department's charges (Bond Charges and Power Charges) to the remaining Customers would not increase due to Customers participating in direct access. The Commission has not established an order relative to direct access charges, but has indicated such fees would be applied to Customers that switched to direct access service between July 1, 2001, the date the Commission first considered suspension of direct access, and September 20, 2001, the final suspension date ordered by the Commission. This determination makes no assumptions regarding revenues realized by the Department from direct access charges.

designs, and related measures. These factors are expected to continue to suppress demand growth within the IOU service areas in the future. The estimated IOU demand and energy requirements discussed later in this section take into account these factors.

With the onset of electricity shortages and the subsequent rise in prices, a number of new conservation initiatives were undertaken during 2000 and 2001, including new rate designs, funding of new initiatives, and Executive Orders. In total, these initiatives are estimated by the CEC to have substantially reduced IOU peak demands during 2001, and included the programs described below.

- The "20/20 Program," established by Executive Order of the Governor on March 13, 2001, provided the Customers with rebates equal to 20 percent of their bills if they reduced consumption by more than 20 percent relative to their consumption for the same period in the previous year. The program applied to the four summer months from June through September during 2001. The CEC estimates the gross program impacts to be 2,200 MW of peak demand savings and 2,743 GWh of energy savings during 2001. Total revenue shortfalls resulting from the program during 2001 were approximately $286 million and were absorbed by the Department.

- Assembly Bill 970 ("AB 970"), signed into law in September 2000, provided $50 million from State funds for conservation and peak demand reduction programs. Funding was provided for 135 projects. The CEC estimates these programs resulted in peak load reductions of approximately 150 MW.

- Assembly Bill 29X ("AB 29X") and Senate Bill 5X ("SB 5X"), signed into law in April 2001, provided an aggregate funding of $500 million from State funds for conservation and peak demand reductions. The CEC estimates that these programs produced approximately 275 MW of peak load reduction during 2001.

- The CPUC's Summer Initiative included a $72 million expansion of ongoing IOU energy conservation programs targeting measures to reduce peak demand during the summer of 2001. The CEC estimates this initiative reduced summer peak demand by approximately 124 MW.

- Conservation and peak load reduction efforts by local and state government that are estimated by the CEC to have reduced their average energy usage by approximately 8 percent from comparable 2000 levels during 2001.

On an aggregate basis, the programs described above are estimated to have had a material impact on the electrical requirements of the Customers during 2001. With the likely exception of the 20/20 Program, new funding for these programs was not continued for 2002. However, the initiatives undertaken during 2001 are expected to provide ongoing load reduction benefits throughout the Second Revenue Requirement

Period. The sales impact of these initiatives have been taken into account by the Department in this determination of revenue requirements.

Usage Adjustments and Price Elasticity Effects

The CEC estimates that total IOU peak demands during 2001 decreased by approximately 1,300 MW as a result of these factors (excluding 20/20 Program reductions described earlier). The IOUs have indicated to the Department that, even though most of the 2001 programs will not be funded in 2002, they expect these factors to continue to influence electrical usage in the future and have taken them into account when preparing the demand and energy forecasts relied on by the Department in this determination of revenue requirements.

Tables E-2 and E-3 show the resulting load and sales forecast (including the adjustment described above) which formed the basis for the Department's determination of revenue requirements.

Power Supply-Related Assumptions

Two types of power supplies needed to meet the requirements of the three IOUs were considered by the Department in its determination of revenue requirements: (a) Supply from Priority Long-Term Power Contracts and (b) the Residual Net Short of the three IOUs.[1]

Table E-4 below shows, for the Second Revenue Requirement Period, the estimated peak demand for each of the three IOUs, the estimated peak demand after adjustments, estimated supplies from generation retained by the three IOUs[2], the resulting net short, the expected supply from the Department's Priority Long-Term Power Contracts, and the Residual Net Short.

[1] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its determination of revenue requirements for the Second Revenue Requirement Period. The section titled "Key Uncertainties in the Revenue Requirement Determination" provides more detail on the issue of supply to meet residual net short requirements during the Second revenue Requirement Period.

[2] Generation retained by the three IOUs includes generation owned by them, supply from contracts between the IOUs and qualifying facilities ("QF's") and other bilateral contracts.

TABLE E-2
ESTIMATED PEAK DEMAND[1]

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[2]	17,207
Less:	
Incremental Conservation and Load Management[3]	228
Self-Generation	90
Direct Access	2,279
Peak Demand After Adjustments[4]	14,610
Southern California Edison Company	
Peak Demand	18,247
Less:	
Incremental Conservation and Load Management[3]	227
Self-Generation	116
Direct Access	1,719
Peak Demand After Adjustments	16,185
San Diego Gas and Electric Company	
Peak Demand	3,935
Less:	
Incremental Conservation and Load Management[3]	45
Self-Generation	50
Direct Access	649
Peak Demand After Adjustments	3,191
All Investor-Owned Utilities	
Peak Demand	39,389
Less:	
Incremental Conservation and Load Management	500
Self Generation	256
Direct Access	4,647
Peak Demand After Adjustments[5]	33,986

[1] All values presented in the table have been adjusted for transmission and distribution losses. Amounts shown for self-generation represent increases above levels experienced historically.
[2] Includes adjustments due to price elasticity effects.
[3] For all three IOUs, these amounts are intended to represent the estimated incremental peak demand reductions resulting from the 2002 20/20 Program to be implemented for the summer of 2002 and the CPA Demand Response program, which is expected to be implemented from 2002 through 2006.
[4] For all three IOUs, these amounts are intended to represent peak demands must be met by electric generating resources or power purchases or a combination of the two.
[5] Represents the sum of the individual IOU amounts. The actual value at the time of the system's coincident peak may be lower.

TABLE E-3
ESTIMATED ENERGY REQUIREMENTS[1]

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company[2]	
Energy Requirements[3]	86,253
Less:	
Incremental Conservation and Load Management[4]	5
Self-Generation	554
Direct Access	12,521
Energy Requirements After Adjustments[5]	73,173
Southern California Edison Company	
Energy Requirements	87,268
Less:	
Incremental Conservation and Load Management[5]	5
Self-Generation	712
Direct Access	9,413
Energy Requirements After Adjustments	77,138
San Diego Gas and Electric Company	
Energy Requirements	20,177
Less:	
Incremental Conservation and Load Management[5]	1
Self-Generation	307
Direct Access	3,846
Energy Requirements After Adjustments	16,023
All Investor Owned Utilities	
Energy Requirements	193,698
Less:	
Incremental Conservation and Load Management[5]	11
Self-Generation	1,573
Direct Access	25,780
Energy Requirements After Adjustments	166,334

[1] All values presented in the table have been adjusted for transmission and distribution losses. Amounts shown for self-generation represent increases above levels experienced historically.

[2] Amounts shown exclude 5,416 GWh of requirements associated with the company's contract with the Western Area Power Administration ("WAPA").

[3] For all three utilities, includes adjustments on account of price elasticity effects.

[4] For all three IOUs, these amounts are intended to represent the estimated incremental energy requirement reductions resulting from the 2002 20/20 Program to be implemented for the summer of 2002 and the CPA Demand Response program, which is expected to be implemented from 2002 through 2006.

[5] For all three IOUs, these amounts are intended to represent energy requirements that have to be met by electric generating resources or power purchases or a combination of the two.

TABLE E-4
ESTIMATED NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[1]	17,207
Peak Demand After Adjustments	14,610
Supply from Utility Retained Generation	10,410
Net Short	4,200
Supply from the Department's Priority Long Term Power Contracts	5,043
Residual Net Short (Surplus)	(843)
Southern California Edison Company	
Peak Demand	18,247
Peak Demand After Adjustments	16,185
Supply from Utility Retained Generation	9,275
Net Short	6,910
Supply from the Department's Priority Long-Term Power Contracts	4,407
Residual Net Short (Surplus)	2,502
San Diego Gas and Electric Company	
Peak Demand	3,935
Peak Demand After Adjustments	3,191
Supply from Utility Retained Generation	814
Net Short	2,377
Supply from the Department's Priority Long-Term Power Contracts	1,193
Residual Net Short (Surplus)	1,184

Table E-5 below presents similar information for the three IOUs in terms of energy requirements during the Second Revenue Requirement Period.

For informational purposes, Table E-6 below shows, for the Second Revenue Requirement Period, the expected average cost (in $/MWh) by quarter for the Department's Priority Long Term Power Contracts, the expected cost of Residual Net Short, and the volume weighted average of the two.

[1] See the discussion under "Load and Sales Forecast Assumptions" for an explanation of the source of data on peak demand for each of the three IOUs.

TABLE E-5
ESTIMATED NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company	
Energy Requirements	86,253
Energy Requirements After Adjustments	73,173
Supply from Utility Retained Generation	52,725
Net Short	20,448
Supply from the Department's Priority Long Term Power Contracts	21,394
Off System Sales of Excess Contract Energy[1]	(4,080)
Residual Net Short (Surplus)	3,135
Southern California Edison Company	
Energy Requirements	87,268
Energy Requirements After Adjustments	77,138
Supply from Utility Retained Generation	55,830
Net Short	21,308
Supply from the Department's Priority Long Term Power Contracts	22,066
Off System Sales of Excess Contract Energy	(4,930)
Residual Net Short (Surplus)	4,172
San Diego Gas and Electric Company	
Energy Requirements	20,177
Energy Requirements After Adjustments	16,023
Supply from Utility Retained Generation	6,289
Net Short	9,734
Supply from the Department's Priority Long Term Power Contracts	6,504
Off System Sales of Excess Contract Energy	(94)
Residual Net Short (Surplus)	3,324

TABLE E-6
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts	Residual Net Short[2]	Weighted Average
Quarter 1 – 2003	108	36	88
Quarter 2 – 2003	128	30	110
Quarter 3 – 2003	101	37	89
Quarter 4 – 2003	105	37	93

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[1] Represents the aggregate energy purchased under the Department's Long-Term Priority Contracts that is in excess of the energy needed to meet the hourly residual net short requirements of the IOUs.

[2] As mentioned earlier, this determination of the Department's revenue requirements assumes that the Department, pursuant to AB1X, is not responsible for providing resources to meet the residual net short of the three IOUs during the Second Revenue Requirement Period. The next section titled "Key Uncertainties in the Revenue Requirement Determination" discusses the implications of a continued role for the Department in providing the residual net short requirement of the three IOUs.

Table E-7 shows, by month for the Second Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from Priority Long Term Power Contracts, and the Residual Net Short.

TABLE E-7
NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2003

Period	Net Short (MWh)	Supply from Long-Term Priority Contracts (MWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (MWh)	Revenues from Off System Sales (Millions of Dollars)	Spot Volume (MWh)	Net Short Costs (Millions of Dollars)
Q1-2003	8,917	10,420	$858	1,502	$19	–	$839
Q2-2003	8,001	11,178	928	3,177	37	–	889
Q3-2003	13,657	15,106	1,255	1,448	19	–	1,236
Q4-2003	11,431	13,688	1,071	2,256	31	–	1,040
Total (1)	42,011	50,399	$4,111	8,388	$109	–	$4,004
(1) May not add due to rounding.							

Finally, Table E-8 below shows the peak capacity and energy supplied by the Department's long-term contracts on an annual basis for the Second Revenue Requirement Period. This information is provided by zone (i.e., SP15 and NP15) and by type of resource.

Natural Gas Price-Related Assumptions

Since mid-2000, natural gas prices in California have fluctuated widely, driven by variations in weather patterns, supply availability, pipeline constraints, and storage inventory levels. In recent months, gas prices have moderated and the Department believes the long-term trend will exhibit a flattening of the price curve, with modest increases in price over the Second Revenue Requirement Period. Between 1996 and 2000, natural gas prices demonstrated a relatively stable pattern, generally averaging approximately $2.20 per MMBtu at Henry Hub on an annual basis. This price behavior changed in May 2000, when prices failed to decline following the end of the winter heating season, despite excess gas in underground storage. As a result of the relatively high price, many buyers delayed purchasing gas for storage injection, expecting prices to decline as summer progressed. The decision to delay these purchases, together with other factors, contributed significantly to major increases in the cost of natural gas during the latter half of 2000 and early 2001. Over the course of 2001, gas prices began to retreat to lower levels. These reductions were influenced by lower than expected demand for natural gas-fired generation during the summer of 2001, an increase in new gas drilling and production levels (driven by the higher prices experienced during 2000), and the gradual slowing of the national and California economies.

TABLE E-8
PEAK CAPACITY AND ANNUAL ENERGY SUPPLIED FROM THE DEPARTMENT'S PRIORITY LONG-TERM POWER CONTRACTS

	Peak Capacity[1] (MW)	Energy (Gigawatt-hours)
Contract Capacity and Energy		
SP 15		
Base Load[2]	1,610	11,110
Peak[3]	2,150	10,416
Dispatchable	1,780	6,200
Renewable/As-Available	60	524
Off-Peak[4]	200	757
Total SP 15	5,800	29,007
NP 15		
Base Load	2,050	15,831
Peak	775	2,735
Dispatchable	2,175	2,472
Renewable/As-Available	43	354
Off-Peak	-	-
Total NP 15	5,043	21,394
Total Contract Capacity	10,843	50,401

The Department has estimated forward natural gas prices using a proprietary forecasting model. The model relates annual natural gas prices to prior period prices, a weather variable reflecting average heating degree-days, and a variable representing drilling activity and well completions to produce a forward price at Henry Hub. The resulting econometric equation is used to estimate future prices. The econometric results of the Department's modeling exhibit strong and reasonable properties in terms of statistical error measurements and, when data inputs are used that reflect historical conditions, the model has produced price estimates that are very close to those actually experienced.

The delivered cost of natural gas is typically the cost at the southern California border plus the cost of intrastate transportation. Southern California border prices are derived by adding a "basis" differential to the Henry Hub price. Resulting gas prices at the Southern California border, Malin, and PG&E's city-gate by quarter for the Second Revenue Requirement Period are shown in Table E-9.

[1] Peak loads can vary by area within California. The Department has assumed that the peak month is July.
[2] Base Load contracts provide full capacity and energy during all months of the year.
[3] Peak contracts generally provide full capacity and energy, Monday through Saturday, from hour ending 0700 through hour ending 2200 each month of the year. Note that this grouping also includes a sub-set of contracts that provide full capacity and energy seven days a week from hour ending 0700 through hour ending 2200 for all months of the year as well as a sub-set of contracts that provide full capacity and energy Monday through Friday from hour ending 0700 through hour ending 2200 for all months of the year.
[4] Off-peak contracts provide full capacity and energy during those hours not generally defined as peak. Off-peak capacity amounts are not added to total peak capacity supply.

TABLE E-9
NATURAL GAS PRICE ASSUMPTIONS
(Dollars per mmBTU)

	SoCal Border	Malin	PG&E City Gate
Q1 – 2003	3.16	2.69	3.14
Q2 – 2003	3.22	2.74	3.20
Q3 – 2003	3.07	2.61	3.06
Q4 – 2003	3.38	2.89	3.35

Assumptions Relating to Spot (Off-System) Sales

As with any retail provider of energy, the Department, from time to time, will purchase more energy than is required to serve its retail customers. This excess energy is sold in wholesale markets in an attempt to provide income to the Department that is used to decrease the Department's revenue requirements to be recovered from the Customers.

The expected average quarterly cost and volume of off-system sales projected to be made by the Department over the Second Revenue Requirement Period is provided in Table E-10 below.

TABLE E-10
OFF-SYSTEM SALES

	Off-System Sales Volume (GWh)	Off-System Sales Revenue (Millions of Dollars)	Weighted Average Cost ($/MWh)
Q1 – 2003	1,502	18	$12
Q2 – 2003	3,177	37	$12
Q3 – 2003	1,448	20	$14
Q4 – 2003	2,256	32	$14
Total	8,383	107	–

Assumptions Relating to Ancillary Service Costs

The Department continues to be authorized to take those actions necessary to implement and administer the power supply contracts in effect as of December 31, 2002, and to ensure delivery of power there under to retail end-use customers. To the extent that the Department must pay for or obtain ancillary services charges from the CAISO for scheduling and delivery of power it continues to have the authority to do so under AB1X.

The volume of ancillary services required in any given hour is based on the load scheduled for that hour. The price for ancillary services is based on prices that result from the day-ahead and hour-ahead bids for such services that the CAISO receives from its ancillary services auction process.

To develop an estimate of expected ancillary service costs for the Department's revenue requirements, it has identified a correlation between energy prices and ancillary services prices. Based on hourly historical price data for the period from April 1998 through December 2000, a regression analysis was performed resulting in an econometric model of ancillary service price (where spinning reserves were used as a proxy for ancillary services) as a function of several variables. Upon performing the regression, the Department identified the primary independent variable driving the price of ancillary services as the price of the residual net short.

To develop the price forecast, the energy market-clearing price forecast and the system load were analyzed using the econometric model. Simulations were then conducted to calculate the forecasts of prices as well as the distributions and confidence intervals of the prices. Based on these simulations, the Department estimates its cost of ancillary services, as calculated below[1]:

[Cost of Ancillary Services = 3.8 percent x Price of Residual Net Short x Power Supplied by DWR]

In addition to these costs, the Department may be required to pay Grid Management Charges (GMC) imposed by the CAISO. The GMC is estimated below.

Service Type	**CAISO Tariff ($/MWh)**
Control Area Services	0.58
Congestion Management	0.37
Ancillary & Real-Time	0.96
Total	1.90

In addition, the Department contracted with California Power Authority to provide 250 MW per month by October 2002 and 500 MW per month by June 2003 of interruptible load capacity. The contract will extend from July 2002 through December 2006 and relies on the interruption of commercial and industrial end-user loads to achieve the targeted demand reductions. These load curtailments are to be available to the Department for up to 24 hours per month for either meeting peak load requirements or providing ancillary services.

Based on the foregoing, the Department estimates that its cost of ancillary services over the Second Revenue Requirement Period will be approximately $172 million for services in support of DWR power sales to retail end-use customers.

Administrative and General Costs

The Department's administrative and overhead costs of $28 million included in Power Charges consist of its labor costs, including benefits, professional service fees,

[1] The allowance for the costs of future ancillary services through the Second Revenue Requirement Period assumes that the Department does not credit back CAISO transactions on behalf of the IOUs.

capital expenditures attributable to its role in the acquisition and management of power supply resources to meet the Customers' net short requirements, and costs billed by the IOUs under the Servicing Arrangements. These costs have been estimated for 2003 based on approved budget levels. Estimated administrative and overhead expenditures for the Second Revenue Requirement Period reflect the transfer of residual net short purchasing requirements to a party other than the Department beginning January 1, 2003.

Financing-Related Assumptions

The Department expects to issue Power Supply Revenue Bonds in the third quarter of 2002. The primary uses of net Bond proceeds will be to (a) repay the then outstanding balance of the $4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately $6.5 billion advanced to the Department for 2001 power purchases and interest that has accrued on the General Fund advances,[1] and (c) fund reserves required to complete the bond financing.

The Department has provided to the Commission the "Summary of Material Terms of Financing Documents" referenced in the Rate Agreement. Any material changes to the financing parameters described in the summary must be approved by the Commission prior to the issuance of the Bonds. The following are key provisions of the summary:

(1) The maximum aggregate bond size will not exceed $11.1 billion.

(2) The final maturity of the bonds will be no less than 19 years and no more than 21 years from the date of issuance of the first series of Bonds.

(3) The summary describes the flow of funds into, within, and between various accounts established under the Bond Indenture.

(4) The summary specifies the methodology for sizing reserves and fund and account balances.

(5) The summary prescribes the maximum level of initial funding for each of the Department's operating and financing-related accounts.

Consistent with these material terms of the financing documents, the Department estimates that the bond charge-related revenue requirement for the Second Revenue Requirement Period will be $808 million[2]

[1] The Department's November 5, 2001 determination of revenue requirements discusses in greater detail the factors that have driven the Department's indebtedness.

[2] Note that this estimate of financing costs excludes amounts associated with debt service reserves. The determination of the exact amount of the initial debt service reserve will be performed as the date for the bond issuance draws closer. Once this determination has been made, the Department will notify the Commission of the impact, if any, on the Bond Charge.

F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

As mentioned earlier, a number of uncertainties facing the Department may require material changes to its determination of revenue requirements for the Second Revenue Requirement Period contained herein. These uncertainties are driven primarily by:

(1) Assumptions regarding participation in direct access programs;

(2) The Department's role in the procurement of net short, including residual net short for the IOUs;

(3) Developments with respect to the bond financing; and

(4) Potential changes in California electricity market design proposed by the CAISO.

Direct Access

In its February 2002 decision implementing the Department's Determination of Revenue Requirements, the Commission acknowledged that "the potential impacts of Direct Access customers' responsibility for a share of the Department's revenue allocation should be addressed on a timely basis" (California Public Utilities Commission, Decision 02-02-052 dated February 21, 2002, page 39). The Department is working with the Commission in analyzing potential approaches to the formulation of "direct access charges" on direct access customers that would minimize the shifting of additional power and bond costs to remaining Department customers.

For purposes of this determination, no incremental participation in direct access, beyond that authorized by the Direct Access Order, is contemplated. In the event legislation (AB 117 or other similar legislation) is enacted, this determination has been developed based on the assumption the legislation will require the payment of direct access charges by all aggregation participants such that the Department is financially indifferent to their participation.

The revenue requirement impact of potential surcharges imposed on direct access customers and provided to DWR is shown in Table F-1.

Transitional Issues Including Procurement of Residual Net Short

In accordance with the Act, the Department's purchase of net short energy requirements is intended to be an interim responsibility. The Act prohibits the Department from entering into new obligations to purchase energy after December 31, 2002. The Department and the Commission are working to transfer all of the Department's net short energy supply responsibilities to the IOUs as soon as practicable, including responsibilities for residual net short purchases and the management of the existing long-term energy contracts.

The Commission initiated a proceeding (Order Instituting Rulemaking 01-10-024) to define the IOUs' responsibilities for net short energy procurement on October 25, 2001. In March 2002, the Department began plans to prepare for the transfer of the net short procurement from the Department to the IOUs. Under the Department's plan:

(1) Effective January 1, 2003, the IOUs will procure the residual net short energy and will schedule energy from the Department's power contracts to meet the hourly energy requirements of the Customers within their respective service territories; and

(2) The Department will continue to administer the Electric Power Fund to meet the Indenture and Bond covenants and monitor its revenue requirements, submitting new revenue requirement requests to the Commission as required under the Rate Agreement.

The Department plans to use the Commission's procurement process as the means to adopt the transition plan and is coordinating with the IOUs in planning for and implementing the transition. Despite the Department's plan however, it is expected that if all of the Department contracts cannot be fully assigned (for financial as well as management of output purposes), the Department will continue on an interim basis to assume financial responsibility, while the IOUs, who will operate under a management/operating agreement with the Department, will manage the output of contracts allocated to them for scheduling, dispatch, billing, and settlements.[1]

Any of the above cases for transfer of the net short to the IOUs presumes the prior creditworthy status of each of the IOUs. To the extent the IOUs are not creditworthy sufficiently in advance of January 1, 2003, either the Commission will need to find a means for the creditworthy IOUs to purchase on behalf of any non-creditworthy IOU, or new legislative or other legal authority to extend the Department's interim role of purchasing of the residual net short will be required. In such an event, it is expected that the Department's projection of retail revenue requirements over the revenue requirement period will change relative to what is contained in this determination. A preliminary estimate of the impact of the Department's continued

[1] The Department's plan contemplates that the transition will begin when the Commission orders the IOUs to accept the Department contracts and assume responsibility for procuring their residual net short. The Commission order will likely coincide with the judgment of creditworthiness of the IOUs by bond rating agencies. The procedure by which this is accomplished is the Commission's procurement process set out in the pending Order Instituting Rulemaking (OIR 01-10-024). The Commission President has established a proceeding schedule for the Commission decision and the subsequent order which would result in a final Commission decision on the net short energy procurement responsibilities of the IOUs by October 1, 2002, and the IOUs assuming responsibility for the full net short purchase or management thereof by no later than January 1, 2003. The completion of the full assignment of the Department contracts to the IOUs, such that the IOUs are responsible for the costs of contracts as part of each IOU's revenue requirement by January 1, 2003, is questionable. However, in the interim, the Commission could provide for a process in which the IOUs manage contract energy scheduling and purchases with continued uniform pro rata allocation of the costs until such time that the contracts can be fully assigned. Alternatively, some of the contracts, and their costs, could be assigned to the IOUs while a portion of the costs remain the financial responsibility of the Department until they can be assigned, and the Department revenue requirement attributable to such contracts can be shifted from the Department to the IOU assignee.

procurement of the residual net short during the Second Revenue Requirement Period is provided in Table F-1.

Sensitivity Analyses. Table F-1 below provides preliminary results from a sensitivity analysis to illustrate the possible revenue requirement impacts of the uncertainties related to direct access, the Department's role in procuring the residual net short energy requirements of the three IOUs in California.

TABLE F-1
RESULTS FROM A SENSITIVITY ANALYSIS

	Direct Access Impact (Millions of Dollars)	**Residual Net Short Impact (Millions of Dollars)**	**Total (Millions of Dollars)**
Total	($490)	$1,120	$630

Note that the results presented in Table F-1 are incremental. The total amounts should be added or subtracted from to the total revenue requirements presented in Table A-1 in order to derive the Department's total revenue requirements over the Second Revenue Requirement Period.

Developments with Respect to the Financing

If bonds are not issued in the third quarter 2002, the Department may be required to pay interest payments on the Interim Loan totaling $105 million and an October 31, 2002 principal payment of $385 million. The total debt service of $490 million is not included in the revenue requirement. Therefore, any delay in the issuance of bonds poses a significant increase in the revenue requirement for 2002.

In addition, the Debt Service on the Interim Loan for calendar year 2003 is $1.691 billion. The debt service on an $11.1 billion bond issuance is expected to be $840 million. Therefore, an additional $851 million would need to be collected through the revenue requirement for calendar year 2003.

Proposed Changes to the California Electricity Marketplace

Finally, proposed changes to the California electricity market may influence the Department's determination of revenue requirements for both the First and Second Revenue Requirement Periods. The CAISO is undergoing a process of redesign for the operation of the transmission system and the movement of bulk (wholesale) power in California. The redesign, called Market Design 2002 ("MD02"), is being carried out in response to orders issued by FERC. The FERC Order on Clarification and Rehearing of December 19, 2001, directed the CAISO to file its revised congestion management proposal and a plan for implementation of a day-ahead market. In addition, the CAISO is responding to the impending expiration on September 30, 2002, of the market monitoring and mitigation program instituted by FERC in its June 19, 2001 Order on Rehearing of Monitoring and Mitigation Plan.

The CAISO introduced its new market design proposals through a Preliminary Report on Project Approach and Key Market Design Elements Under Consideration on December 21, 2001. The Preliminary Draft Comprehensive Design Proposal was released on January 8, 2002, followed by a series of technical workshops. Since then, the CAISO has received comments, made additional presentations, including to the CAISO Board, and developed its comprehensive market design proposal. In addition, the CAISO has determined that certain elements of the comprehensive market design can be postponed while others must be in place by October 1, 2002, when FERC's western energy markets mitigation plan expires.

MD02 consists of ten parts:

(1) Available Capacity ("ACAP") Obligation. Load-serving entities will face an obligation to maintain an ACAP, defined as a percentage margin above their monthly peak load, through a combination of their own generation, firm energy contracts, capacity contracts, and demand-side management.

(2) Forward Congestion Management ("CM"). The CAISO proposes to use a full network model to adjust schedules to clear congestion.

(3) Firm Transmission Rights ("FTRs"). Redesign of CM requires redesign of FTRs.

(4) Forward Day-Ahead Spot Energy Market. The Day-Ahead market will perform energy trades within the CM procedures.

(5) Residual Forward Unit Commitment. After the close of the day-ahead market, the CAISO will determine whether there is a need for additional generation resources to be brought on-line for the next day's needs.

(6) Ancillary Services. Bidders will be required to submit a single energy curve for all services offered by a particular resource. Currently, different energy curves may be submitted for each ancillary service for which a resource is qualified.

(7) Modification to the Hour-Ahead Market. The Hour-Ahead market will be simplified by performing only CM and energy trading.

(8) Real-time Economic Dispatch Using a Full Network Model. This will be a 10-minute dispatch that will take into account inter- and intra-zonal congestion, resulting in nodal real-time prices.

(9) Real-time Bid Mitigation for Locational Needs. This will reduce local market power.

(10) Damage Control Price Cap on CAISO Markets. Beginning October 1, 2002, and continuing until market conditions are competitive enough to support a higher price cap, the CAISO proposes to set the price cap at three times

the estimated variable cost of a gas-fired generating unit with an incremental heat rate of 20,000 or $250 per MWh, whichever is greater.

On May 1, 2002, the CAISO made a comprehensive filing to FERC consisting of specific tariff language proposed to go into effect on October 1, 2002, coincident with the end of the FERC mitigation plan. In addition, the filing contains language describing the comprehensive market design proposed to be implemented over time, with specific tariff language to be supplied in a filing in mid-June, 2002.

The CAISO released Draft October First Design Elements on March 27, and released proposed tariff language for the October First Design Elements on April 19. The elements proposed for October 1, 2002, are simplified from the comprehensive market design and represent the first phase of the CAISO's efforts to implement the above changes. The changes proposed for October 1, 2002, include the following eight elements.

(1) Must-Offer Obligation. This is similar to the current must-offer obligation under the FERC's western mitigation system.

(2) Residual Unit Commitment ("RUC"). This will be similar to the RUC system proposed in the comprehensive design, with the exception that the October 1, 2002, version allows for competition between intertie energy bids and internal units.

(3) Changes to Day-Ahead and Hour-Ahead Markets. Bidders will submit a single bid for all energy and ancillary services.

(4) Damage Control Bid Cap. This will be a single cap for all energy and ancillary services.

(5) Bid Screens and Mitigation. There will be individual resource bid screens to mitigate bids that exceed explicit threshold limits and have a material effect on projected market-clearing prices.

(6) 12-Month Market Competitiveness Index and Pre-authorized Additional Mitigation Provisions. This is to be an explicit measure of the competitiveness of the market to determine if or when the market should be declared unjust and unreasonable.

(7) Other Market Power Mitigation Measures. This will include local market power mitigation measures and penalties for failure to honor binding real-time bids.

(8) Transitional Available Capacity Obligation. Because the ACAP is not likely to be feasible by the beginning of October 2002, the CAISO proposes a monthly assessment process to take account of all available resources, including DWR power contracts, and will identify a potential shortfall

early enough to enable load-serving entities and other responsible parties to procure additional supply.

Until such time that the CAISO has gone through its market design process, and FERC has acted, it is difficult to determine which, if any of the modifications proposed by the CAISO will be adopted, if any. The uncertainty of the ultimate decisions has precluded any modeling of the possible effects of such market restructuring on the net short energy requirements and their costs, or the cost of energy in the spot market in the future. The Department intends to continue monitoring the California market restructuring efforts. If there are material changes to the market, the Department will evaluate the effects of such changes. If the changes are expected to have a material effect on the Department's net short energy purchases and resultant revenue requirement, the Department would notify the Commission and, if necessary, modify the Department's revenue requirement accordingly.

APPENDIX 1 MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, the supply and price of natural gas and coal, the power transfer capability of major interties, the operating cost, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. To analyze the fundamental drivers underlying the electricity market, the Department completed computer simulations of market activity throughout the Western Electric Coordination Council ("WECC") region. To complete those simulations, the PROSYM price forecasting and market simulation tool was used.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America, and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this revenue requirement determination, the demand and energy forecasts used were those that have been described earlier.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only "single-price" market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment. In the near-term, the use of a single-price mechanism for the residual net short produces a conservative assessment of market prices.

Within the PROSYM framework, bid prices are developed for each unit and reflect the minimum clearing price the generator is willing to accept to operate. Market-clearing prices reflect the bid of the last generating resource used to meet the last increment of demand. The clearing price also includes an uplift component reflecting start-up and no-load costs of the marginal unit. Station revenues are based on these market-clearing prices within the market area in which the plant is located or assigned.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = *Incremental Production Cost* + *Start Cost* + *No-Load Cost* + *Price Markup*

Where:

- Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;

- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;

- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and,

- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets, and has been particularly present in California markets during the last year.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

(1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.

(2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy.

(3) Peak Period Bidding: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on-peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in this study. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

**CALIFORNIA AND WECC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)**

	Incremental	Price Markup	Peak Period Bidding	Total
California	68%	28%	4%	100%
Non-California	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

FERC Price Mitigation

On June 19, 2001, FERC issued an order on price mitigation throughout the WECC. Under this order, a soft price cap is set for the entire WECC based on the heat rate of the least efficient unit and the average natural gas price during the most recent Stage 1 Emergency ("Stage 1") warning period issued by the CAISO. During a Stage 1 (or higher) warning period, the cap is equal to the energy cost resulting from the heat rate of the least efficient resource being utilized in the market and the average natural gas price in California, plus a $6.00 per MWh cost for operation and maintenance expenses. A 10 percent risk premium is added for energy sold in California. Under this formula, the effective Stage 1 cap in California, if the least efficient generator were operating at 18,000 Btu per kWh and the average price of gas were $5.67 per MMBtu, would be $118.90 per MWh. If a Stage 1 warning or higher is not in effect, the effective cap is calculated as 85 percent of the last Stage 1 cap in effect. As an example, using a $118.90 per MWh Stage 1 cap, the non-Stage 1 cap would be $101.06 per MWh (85 percent of the Stage 1 value). The Stage 1 cap is reset during each successive CAISO Stage 1 warning.

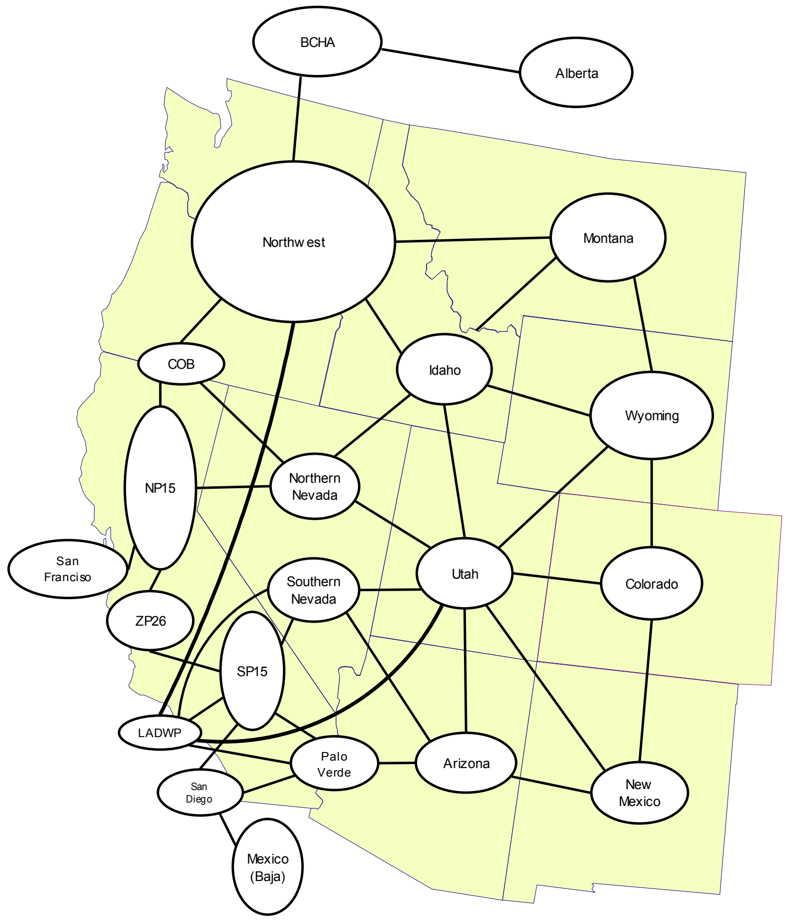
For purposes of this determination of revenue requirements, the Department has assumed that the non-Stage 1 cap presently in effect ($101.06 per MWh) does not change through September 30, 2002 (the expiration date of the FERC order).

WECC Regional Market Definitions

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation takes into account economic import and export possibilities and sets the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.



Simulation of New Resource Additions

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Those resources only announced or under feasibility study were added to the simulation resource base only if the annual average market-clearing price in the year of completion is forecast to exceed that which provides a threshold return on equity (these resources are designated for "planning capacity"). Energy revenues (hours of operation multiplied by energy prices) must be greater than the average annual costs (fuel and capacity) of the project. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the Second Revenue Requirement Period.

GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new generating units are assumed to be added to the resource mix.

Long-Term Power Contracts

The Department's contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the utility retained generation, the Department's contracts, and residual net short purchases.

Other Assumptions

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2002 through December 2003.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Report.
Load Profiles	Derived from hourly Edison Electric Institute load data files for each utility from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years. Amounts derated during 2002, as described in the Report.
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources. Amounts derated during 2002, as described in the Report.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	• Multi-segment incremental heat rate curves. • Fixed and variable O&M costs. • Scheduled outages based on annual maintenance cycles. • Random forced outages based on unit-forced outage rates.
Contracts	• Known firm purchase/sales reported in the WECC Form OE-411 filing. • Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity. • Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

APPENDIX 2 SUMMARY OF THE MATERIAL TERMS OF THE PROPOSED FINANCING

The following information has been excerpted from the Rate Agreement between the Department and the Commission.

Maximum Amount of Bonds Authorized

The Department will issue no more Bonds than it determines are necessary to repay advances from the General Fund and the Interim Loan, to fund the reserves and accounts as described below and to pay costs of issuance using all Bond proceeds and all Department Electric Power Fund balances available at the time of issuance of the Bonds; provided, however, the maximum aggregate principal amount of Bonds which will be issued will not exceed $11.1 billion.

Maturity of Bonds

The Bonds will be issued pursuant to a plan of finance which provides that the final maturity of the series of Bonds with the longest maturity will be no earlier than 19 years from the date of issuance of the first series of Bonds and no later than 21 years from the date of issuance of the first series of Bonds. Such plan of finance will provide that debt service payable on the Bonds will be substantially level, with principal payments commencing no later than 2004. Individual series of bonds issued pursuant to such plan of finance, or individual Bonds of any series, may mature prior to such final maturity date and have different amortization schedules. These maturity dates and amortization requirements do not apply to credit and liquidity facilities, interest rate swap agreements and similar arrangements ancillary to the Bonds.

Flow of Funds

The Indenture will provide for the establishment of the following primary accounts within the Electric Power Fund:

- Operating Account
- Priority Contract Account
- Bond Charge Collection Account
- Bond Charge Payment Account
- Debt Service Reserve Account
- Operating Reserve Account
- Administrative Cost Account

Power Charge revenues and Bond Charge revenues will be applied in the manner summarized below. Such revenues will be applied in the order of priority listed.[1]

Power Charge Revenues. Power charge revenues result from charges imposed by the PUC upon Retail End Use Customers for electric power deemed sold to Retail End Use Customers by the Department, except that Power Charges exclude Bond Charges. Power Charge Revenues are initially deposited in the Operating Account.

Bond Charge Revenues. Bond Charge Revenues result from charges imposed by the PUC upon customers in each of the IOUs service areas based on the aggregate amount of electric power sold to that customer by an Electrical Corporation and the Department. Bond charges shall be imposed upon customers at all times whether or not the Department is selling Power to such customers, until such time as the Department has recovered the portion of the Department's revenue requirements for bond-related costs. Bond Charge Revenues are deposited in the Bond Charge Collection Account.

Operating Account

Amounts held in the Operating Account will be applied as follows:

1. Transfer to Priority Contract Account, by the fifth business day of each month, an amount such that balance held in that account is at least equal to the Priority Long Term Power Contract costs anticipated for the balance of the month and the first five business days of the next following month. If necessary, additional amounts will be transferred to Priority Contract Account as necessary to pay Priority Long Term Power Contract costs.

2. Pay operating expenses, except those described in another paragraph.

3. Pay scheduled principal and interest on the Interim Loan, if and to the extent it remains outstanding.

4. Transfer to Bond Charge Collection Account to extent necessary to reimburse that Account for previous transfers from the Bond Charge Collection Account to (1) Priority Contract Account for payment of Priority Long Term Power Contract costs or (2) Operating Account for payment of Interim Loan.

5a. Transfer to Bond Charge Payment Account, if there are insufficient moneys in the Bond Charge Payment Account to pay debt service.

5b. Pay certain Department obligations to be secured on a parity with Bonds such as amounts due to credit or liquidity facility providers or providers of interest rate swaps (hereinafter referred to as "Parity Obligations"), if not paid from Bond Charge Payment Account.

[1] Where different uses are described with the same number followed by a letter, this indicates that revenues will be applied to such different uses on a parity basis.

5c. Pay bond trustee and other fiduciary costs, if not paid from Bond Charge Payment Account.

6a. Replenish Debt Service Reserve Account, if required as result of the use of Bond Charge revenues for Priority Long Term Power Contract costs or Interim Loan, or a change in investment value.

6b. Fund and replenish reserves, if any, established for Parity Obligations.

7. Reimburse and pay interest on post-11/15/01 advances, if any, from General Fund if and to the extent they remain outstanding.

8. Reimburse and pay interest, in accordance with a schedule to be approved by the Commission, on pre-11/15/01 advances from General Fund if and to the extent they remain outstanding.

9. Replenish Operating Reserve Account to its requirement.

10. Pay subordinated Department obligations such as certain amounts owed to interest rate swap counterparties in certain circumstances (hereinafter referred to as "Subordinated Obligations") and related reserves if not paid from Bond Charge Payment Account, and subordinated indebtedness and related reserves, if any.

11. Pay other costs incurred by the Department under the Act.

Priority Contract Account

The Priority Contract Account is to provide solely for the payment of amounts due under Priority Long Term Power Contracts. Amounts are transferred to the Priority Contract Account from the Operating Account and from the Operating Reserve Account.

Bond Charge Collection Account

Bond Charge Revenues are initially deposited in the Bond Charge Collection Account. Amounts in the Bond Charge Collection Account will be applied as follows:

1. Transfer to Priority Contract Account for Priority Long Term Power Contract costs, if not paid from Priority Contract Account, Operating Account or Operating Reserve Account.

2. Transfer to Operating Account for Interim Loan, if not paid from Operating Account or Operating Reserve Account.

3a. Transfer to Bond Charge Payment Account for monthly deposits to provide for Bond debt service three months prior to the date such debt service is due.

3b. Transfer to Bond Charge Payment Account for specified costs incidental to payment and security of Bonds (including credit and liquidity facility costs).

3c. Transfer to Bond Charge Payment Account for trustee and other fiduciary costs.

3d. After Department is no longer selling Power, pay Servicing Agreement costs, administrative costs, and certain other costs incurred by the Department under the Act.

4a. Replenish Debt Service Reserve Account, if not replenished from Operating Account.

4b. Fund and replenish reserves, if any, for Parity Obligations.

5. After Department is no longer selling Power, pay certain costs specified in Rate Agreement that previously had been paid from Power Charge revenues.

Bond Charge Payment Account

Funds are transferred from the Bond Charge Collection Account no later than the last business day of each calendar month, sufficient to maintain a balance for the following purposes:

1. Debt Service accrued and unpaid to accrue through the end of the third next succeeding calendar month.

2. Amounts accrued and unpaid for the next 3 months, for agreements with issuers of credit and liquidity facilities entered into in connection with the Bonds.

3. Amounts accrued and unpaid for the next 3 months, for the cost to the Department of Fiduciaries associated with the issuance and administration of the Bonds.

4. Amounts accrued and unpaid for the next 3 months, for the Department's Bond charge servicing costs.

5. The redemption Price of any bonds called for redemption, other than for sinking fund requirements.

6. The Trustee to pay interest and principal, and redemption amounts from this account.

7. Trustee to pay Parity Obligations and to other persons as specified.

Debt Service Reserve Account

The Department will pay into the Debt Service Reserve Account an amount to equal the debt service reserve requirement, from Bond proceeds or other available funds

1. Moneys in account used to satisfy any deficiency that arises in the Bond Charge Payment Account.

2. Debt Service Reserve Account to be replenished from Power Charge revenues if a deficiency therein results from use of Bond Charge revenues for Priority Long Term Power Contract costs or Interim Loan, or from change in investment value, and from Bond Charges in other cases or if sufficient Power Charge revenues are not available for such purpose.

Operating Reserve Account

Whenever bonds are issued, the Department shall pay into the Operating Reserve Account from the proceeds or from other funds, the amount required to equal the Operating Reserve Account Requirement.

1. Moneys in Operating Reserve Account will be used to satisfy any deficiency that arises in Operating Account. Such moneys to be applied in order of priority and for the purposes specified in 1 through 6 under Power Charge Revenues above. A portion of the Operating Reserve Account (the "Priority Contract Contingency Reserve Amount") will be reserved solely for the payment of Priority Long Term Power Contract costs as described below, as the last money in the Operating Reserve Account to be spent.

2. The Operating Reserve Account is to be replenished from Power Charge revenues, after reimbursement, in accordance with a schedule approved by the Commission, of amounts advanced from the General Fund if not previously repaid.

Administrative Cost Account

Funds are received from the Operating Account or, if the Department is no longer selling power, the Bond Charge Collection and Payment Accounts, the funds necessary to pay administrative costs.

All Administrative costs of the Department incurred in administering Division 27 of the Water Code shall be paid from this account.

Sizing or Methodology for Sizing Reserves, Fund Balances and Debt Service Coverage; Initial Deposits

Reserves, Fund Balances and Coverage

(1) **Debt Service Reserve Account:** A Debt Service Reserve Account requirement will be established in an amount equal to 50 percent of maximum aggregate annual debt service, determined based on

combination of known debt service in the case of fixed rate bonds and assumed rates in the case of variable rate bonds. The size of such Debt Service Reserve Account requirement may be increased to an amount not greater than 100 percent of maximum aggregate annual debt service by the Department only if the Department has determined that such increase will not increase the Department's projected net debt service on the Bonds by more than 3.5 percent as compared to the Department's projected net debt service that would have otherwise been payable if the Debt Service Reserve Account requirement were established at 50 percent of maximum aggregate annual debt service, taking into account all dependent variables, including the respective ratings of the Bonds.

(2) **Operating Reserve Account:** An Operating Reserve Account requirement will be calculated by the Department prior to the issuance of the first series of Bonds and at the beginning of each revenue requirement period including the Priority Contract Contingency Reserve Amount referred to below. Such requirement is to be equal to the largest aggregate difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any consecutive seven month period starting during the then current revenue requirement period, taking into account a range of possible future outcomes, but may be increased to an amount not to exceed $1.2 billion at the time of issuance of the Bonds. The Priority Contract Contingency Reserve Amount is to be the maximum amount projected to be payable on Priority Long Term Power Contracts in any month during the then current revenue requirement period.

(3) **Operating Account:** The Department will covenant to include in its revenue requirements amounts sufficient to cause a "Minimum Operating Expense Available Balance" to be on deposit in the Operating Account by the first business day of each month. The Minimum Operating Expense Available Balance is to be calculated by the Department at the time of each determination of a revenue requirement and will be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes.

(4) **Coverage:** To provide for coverage of Bond Related Costs, the Department will be required to set aside in the Bond Charge Payment Account, three months prior to its payment date, an amount equal to estimated Bond Related Costs, based on assumptions and projections as appropriate, and to determine the Department's revenue requirements submitted to the Commission so that the amount in the Bond Charge Collection Account from time to time is equal to one month's estimated Bond Related Costs, based on assumptions and projections as appropriate. Such deposit

requirements may be increased to cover a period of time not in excess of an aggregate of six months.

Initial Deposits

Funds are anticipated to be deposited from Bond proceeds or Department balances, upon the issuance of the initial or subsequent series of Bonds, as summarized below.

(1) To the Bond Charge Collection Account and Bond Charge Payment Account, amounts necessary to initially satisfy the requirements described in "Coverage" above.

(2) To the Bond Charge Payment Account, an amount to fund debt service on Bonds and other Bond Related Costs between the time the Bonds are delivered and the time when the initial Bond Charges are fully in effect and being received in amounts adequate to fund ongoing debt service, only if such amounts are not expected to be available from Power Revenues.

(3) To the Debt Service Reserve Account, an amount equal to the Debt Service Reserve Account requirement referred to above.

(4) To the Operating Account, an amount equal to the Minimum Operating Expense Available Balance referred to above.

(5) To the Operating Reserve Account, an amount equal to the Operating Reserve Account requirement referred to above, including the Priority Contract Contingency Reserve Amount referred to above.

(6) To the Priority Contract Account, an amount equal to the maximum projected monthly amount due on Priority Long-Term Power Contracts during the current revenue requirement period.

APPENDIX 3 REFERENCE INDEX OF MATERIALS UPON WHICH DEPARTMENT RELIED TO MAKE DETERMINATIONS

Quasi-Legislative Record of Revenue Requirement Reasonableness Determination

Renegotiated Power Contracts

- Calpeak Power LLC Agreements
  - Border
  - El Cajon
  - Enterprise
  - Midway
  - Panoche
  - Vaca-Dixon
  - Mission Termination Contract
  - Settlement Agreement

- CalPine Energy Services, L.P.
  - CalPine 1
  - CalPine 2
  - CalPine 3
  - CalPine 4
  - Settlement Agreement

- Constellation Power Source, Inc./High Desert Power Project, LLC
  - Constellation
  - High Desert
  - Settlement Agreement

- Whitewater Energy Corporation
  - Whitewater Hill
  - Cabazon

Federal Energy Regulatory Commission Orders

- Order Directing Remedies for California Wholesale Electric Markets in Dockets Nos. EL00-95-000 and related cases (December 15, 2000)
- Order Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40 in Docket Nos. ER 01-3013-000 and ER 01-899-008 (November 7, 2001)

California Public Utilities Commission Decisions and Agreements

- Rate Agreement By and Between the State of California Department of Water Resources and State of California Public Utilities Commission (March 8, 2002)

- Rate Agreement between the CPUC and DWR (CPUC Proceedings A.00-11-038, A.00-11-056, A.00-10-028)
- Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development (CPUC Proceeding R.01-10-024)

Declarations of Peter S. Garris, Raymond D. Hart, and Ronald O. Nichols in Opposition to Motion for Issuance of Writ of Mandate in *Pacific Gas and Electric Company v. California Department of Water Resources and Thomas M. Hannigan*

PROSYM Model